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Pollution Control Practices Cost for Control of SO2 Emissions

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16. ABSTRACT The paper gives results of a study (part of a multiphased EPA study of the acid rain problem) the objectives of which were to (1) identify and characterize existing industrial sources of SO2 emissions, (2) identify the control techniques that can be used to reduce SO2 emissions from these sources, and (3) estimate the SO2 emission reduction potential and associated costs based on applying these controls. Only a portion of the SO2 sources were investigated in detail; simplifying assumptions were made about the balance of the SO2 sources studied. The availability of low sulfur fuels (i.e., physically cleaned coal and low sulfur fuel oil) was not evaluated. In addition, since sites were not visited, the remaining useful lives of the sources were not determined and average flue gas desulfurization unit retrofit factors were estimated. Study results indicate that: (1) application of the proposed control techniques would reduce industrial emissions in plants emiting 4,454 metric tons/year (mt py) or more by 63% or 2,050,000 mtpy of SO2; (2) it would cost $3 billion in capital charges and incur annual operating costs of $1.23 billion; (3) the overall cost per metric ton of SO2 removed is $600; (4) applying controls to the top 257 sources would reduce SO2 emissions in the states east of the Rocky Mountains by 12%; and (5) if applied only to the top 39 plants, the reduction would be 7%.

17. KEY WORDS AND DOCUMENT ANALYSIS

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Pollution	Pollution Control	13B
Acidity	Stationary Sources	07D
Rain	Acid Rain	04B
Sulfur Oxides		07B
Cost Analysis		14A
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Figure 1. Acid rain mitigation study (ARMS region is shaded).

POLLUTION CONTROL PRACTICES:

Cost for Control of SO_2 Emissions

Based on a preliminary study, proposed control techniques applied would reduce industrial emissions from plants emitting 5,000 ton/yr (4,454 metric ton/yr) SO_2 or more by 63%.

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There is a growing concern about the acidity of precipitation in the northeastern United States and Canada. Acidic precipitation is thought by many scientists to kill aquatic and plant life, damage crop-growing soil, and accelerate erosion and damage to buildings. Although the mechanisms producing acid rain are not clearly understood, sulfur dioxide is estimated to be the precursor of the chemical that causes between 40 and 60% of the acidity. Nationally, 69% of the SO_2 emissions come from utilities and 21% from industry (*1, 2*).

Because of this growing concern, the U. S. Environmental Protection Agency (EPA) initiated a multi-phased study of the acid rain problem. As part of this study, the Radian Corp. performed a preliminary study which investigated SO_2 emissions and controls in the industrial sector, while Teknekron, Inc. made a similar study of the utility sector.

Since the major region of concern is the northeastern United States and eastern Canada, only those states fully east of the Rocky Mountains are considered, Figure 1. This is termed the Acid Rain Mitigation Study (ARMS) region.

The objectives of the study were to: 1) identify and characterize existing industrial sources of SO_2 emissions; 2) identify the control techniques that can be used to reduce SO_2 emissions from these sources; and 3) estimate the SO_2 emission reduction potential and the associated costs based

Table 1. 480 largest industrial and utility SO_2 emitters.*

Sector	Number of Plants	SO_2 Emissions (10^6 m ton/yr)
Industrial	186	2.26
Utility	294	15.31
Total	480	17.57

*From 1977 survey on the plants east of the Mississippi River.

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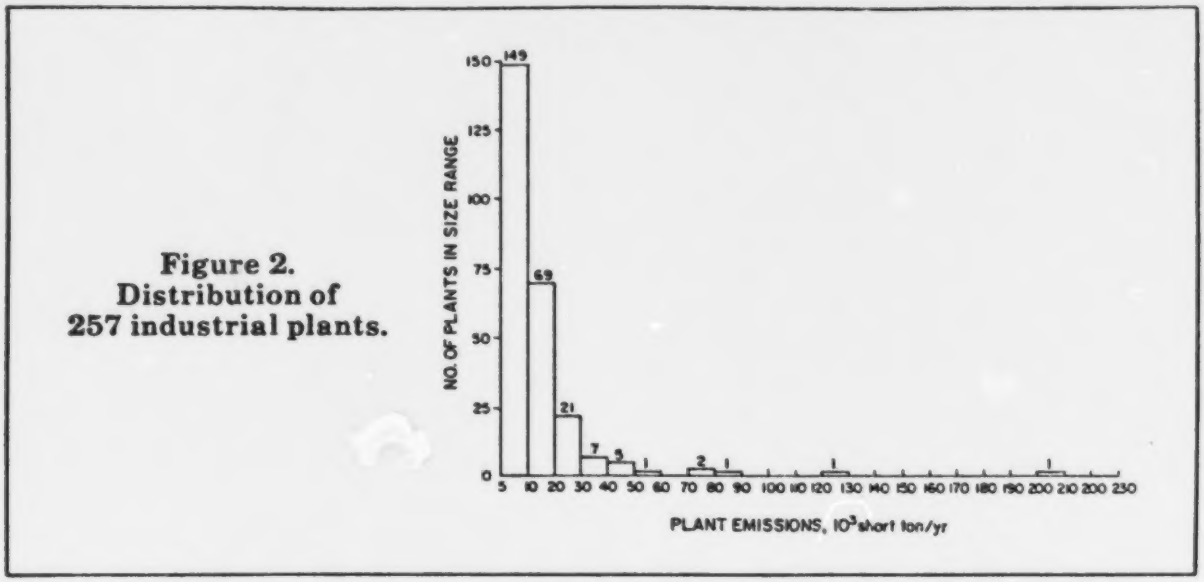


Figure 2. Distribution of 257 industrial plants.

on application of these controls. Only a portion of the SO_2 sources were investigated in detail. Simplifying assumptions were made about the balance of the SO_2 sources studied.

It should also be noted that, the availability of low-sulfur fuels (i.e., physically cleaned coal and low-sulfur fuel oil) was not evaluated. In addition, since site visits were not made, the remaining useful lives of the sources were not determined and "average" flue gas desulfurization unit retrofit factors were estimated.

Emission reduction techniques

The SO_2 emissions data from those industries located in states east of the Mississippi River was obtained from the Multistate Atmospheric Power Production Pollution Study (MAP3S) which is administered by Brookhaven National Laboratory. The data for the other states were obtained from the National Emissions Data System (NEDS) which is collected by EPA's National Air Data Branch.

The MAP3S data revealed that over 90% of the SO_2 emissions from industrial and utility sources east of the Mississippi River came from the 480 plants having the greatest emissions, Table 1. Since the 480th plant produced nearly 5,000 ton/yr of SO_2 (4,530 metric ton/yr), it was decided to limit the study to all industrial plants in the ARMS region which emitted more than this amount.

Including those plants west of the Mississippi River, but still in the ARMS region, gave a total of 257 industrial plants with emissions exceeding 5,000 ton/yr of SO_2 (4,530 m ton/yr). The distribution of these by size, based on the 1977 survey, is given in Figure 2. From this, it can be seen that 39 plants exceed 20,000 ton/yr (18,100 m ton/yr) of SO_2. These 39 plants were evaluated in detail and estimates made of the emissions from the remaining 218 plants. The top 39 industrial plants emit 1,615,000 ton/yr (1,460,000 m ton/yr); the smaller 218 plants emit 1,917,000 ton/yr of SO_2 (1,740,000 m ton/yr). A breakdown of the emissions from the top 39 plants is given in Table 2. The total number of conventional boilers located at these 39 plants is 264.

The only SO_2 control techniques considered were physical coal cleaning, oil desulfurization, limestone flue gas desulfurization, and sulfuric acid production plants. Coal cleaning was used for boilers having a capacity of less than 75 MW_t (thermal input) which used greater than 2% sulfur coal. A level-3 coal-cleaning operation was selected which would reduce the sulfur level of the raw coal by 30%. It would increase the cost of the coal delivered by $4.28/ton in 1980 dollar ($4.72/metric ton) (*3, 4, 5*).

Single-stage oil hydrodesulfurization was used to reduce the average sulfur composition of the oil from 1.64 to 0.8% (*6, 7, 8*). It was estimated this would increase the cost of all oil by $2.50/bbl ($15.70/m^3) (*9*). For both physical coal cleaning and oil desulfurization, it was assumed that another corporation operated the precombustion clean-up facilities. Thus, the only costs to the boiler operator were increased fuel charges.

Flue gas desulfurization (FGD) was used for all boilers having capacities of 75 MW_t or above which burn greater than 2% sulfur coal. It was also used for all non-boiler sources in the metals and process industries with the exception of two smelting operations where it was known that sulfuric acid plants had been used on similar facilities (*10, 11*). The capital costs for new FGD installations are given in Figure 3 (*12*). The design basis for the FGD system is a reduction in emissions of 90%. Since we are dealing with retrofits, these capital figures must be multiplied by 1.3.

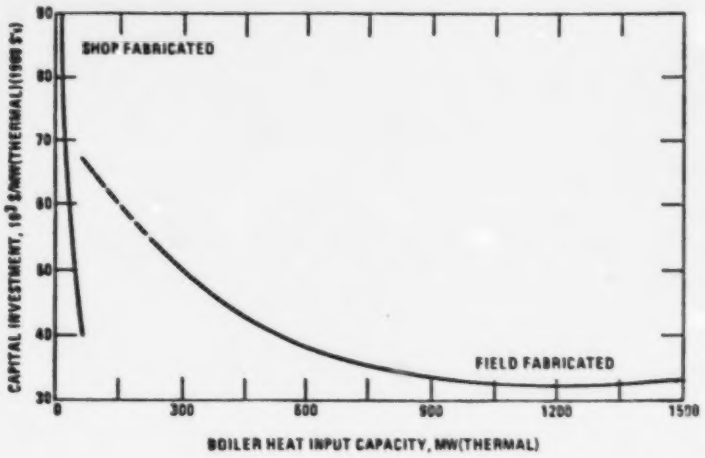
The annual costs given in Figure 4 include a capital recovery factor of 13%. This is based on the capital cost of a retrofitted facility. The operating and maintenance costs which were included are the same as for a new FGD unit.

Calculation of values

SO_2 emissions from plants emitting between 5,000 and 20,000 ton/yr (4,530 and 18,100 m ton/yr) were not characterized individually. In addition, the mixture of industries in the 218 smaller plants was different from those in the 39 larger plants. Therefore, an extrapolation of the emission inventory information for the larger 39 plants to the smaller 218 plants was considered inappropriate.

The 218 facilities were characterized by making the following assumptions: 1) the approximately 2 million ton/yr of SO_2 (1.81 m ton/yr) emitted resulted exclusively from coal-, oil-, and gas-fired boilers; 2) the distribution of SO_2 emissions between coal-, oil-, and gas-fired boilers was the same as that of boilers in plants emitting more than 20,000 ton/yr (18,100 m ton/yr); 3) the size distribution of boilers for plants emitting more than 5,000 ton of SO_2 per year (4,530 m ton/yr) was similar to the nation-wide distribution

Figure 3. Capital invested in limestone FGD.



of industrial water-tube boilers; and 4) the percent sulfur in coal, oil and gas was the same as the fuel-weighted averages for the top 39 plants.

The top 39 plants had 264 boilers which emitted a total of 695,300 ton/yr of SO_2 (630,000 m ton/yr): 68.9% from high sulfur coal; 24.8% from oil; and 6.3% from process gas. Applying these percentages to the 2 million ton/yr of SO_2 (1.81 million m ton/yr) emitted from the remaining 218 plants resulted in a distribution of 1,378,000 ton/yr of SO_2 (1,249,000 m ton/yr) from high-sulfur coal-fired boilers, 496,000 ton/yr of SO_2 (450,000 m ton/yr) from oil-fired boilers, and 126,000 ton/yr of SO_2 (114,000 m ton/yr) from process gas-fired boilers.

The boiler population was distributed by size in accordance with a distribution reported by PEDCo Environmental, Inc. (*12*). This information is summarized in Table 3. Boilers with capacities below 30 MW_t were ignored. The boilers already characterized in the top 39 plants were subtracted from the boiler population to yield the number of potential boilers remaining nation-wide, Table 4.

The total potential heat input to these boilers was next used to apportion the SO_2 emissions within these categories. The total potential heat input for each size category was obtained by multiplying their size by the potential number of boilers. The percent of total capacity by boiler size and type of fuel was then obtained. This percentage was multiplied by the appropriate SO_2 emissions obtained from each fuel type, Table 5.

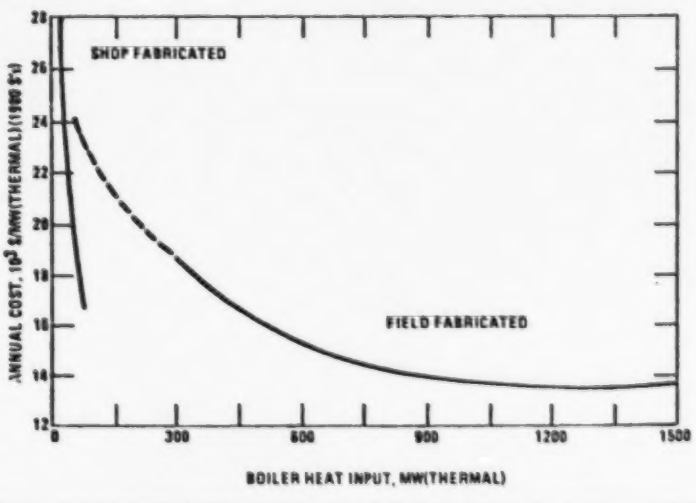
The previous calculations gave the total yearly SO_2 emissions for each fuel by boiler size. To determine the number of equivalent boilers of each size, the yearly SO_2 emissions from a typical boiler of that size must be known. To calculate these values the following assumptions were made.

- Heating values for the three fuels were:

  Coal – 11,500 Btu/lb – 26,740,000 J/kg

  Oil – 18,500 Btu/lb – 43,031,000 J/kg

Figure 4. Annual cost for limestone FGD.



Gas – 1,000 Btu/ft³ – 37,259,000 J/m³

- Boiler capacity utilization factor – 0.6
- 95% of sulfur in fuel emitted as SO_2
- Average sulfur contents for each fuel were:

Coal – 2.41%

Oil – 1.64%

Gas – 0.80%

The number of equivalent boilers was calculated by dividing the tons of SO_2 emitted annually, from Table 5, by the tons of SO_2 emitted annually by each boiler. For example, a 45 MW_t (150 × 10^6 Btu/h) coal-fired boiler will emit:

$$150 \times 10^6 \frac{\text{Btu}}{\text{h}} \times 8{,}760 \frac{\text{h}}{\text{yr}} \times 0.6 \times \frac{1 \text{ lb Coal}}{11{,}500 \text{ Btu}} \times 0.0241 \frac{\text{lb Sulfur}}{\text{lb Coal}} \times \frac{2 \text{ lb } SO_2}{\text{lb Sulfur}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} \times 0.95$$

= 1.6 ton of SO_2 per year

= 1.45 metric ton of SO_2 per year

Therefore, there would be 685,000 ton/yr SO_2 (622,000 m ton/yr), Table 6, divided by 1.6 ton/yr of SO_2 (1.45 m ton/yr) per boiler, or the equivalent of 429 boilers with 45 MW_t capacity in the 218 plants. The results of these distribution calculations are summarized in Table 6.

The same SO_2 emission reduction techniques were used for these boilers as were used for the boilers in the top 39 plants.

Table 2. Industrial SO_2 emissions from 39 largest SO_2 emitters.*

Process	SO_2 Emissions (10^3 m ton/yr) Per Process	Total	% of Total
Boilers		706.0	45.8
Coal-Fired (>100 MW_t)	356.1		
Coal-Fired (<100 MW_t)	78.9		
Oil-Fired	156.6		
Gas-fired	39.4		
Metals Industry (Excluding Boilers)		489.0	31.8
Copper Smelting	214.1		
Iron and Steel	104.6		
Coke Metallurgy	90.0		
Lead Smelting	77.5		
Aluminum	2.8		
Other Industrial Processes (Excluding Boilers)		317.7	20.6
Cat Crackers	64.7		
Process Heaters	54.7		
Cement Kilns	49.2		
Sulfuric Acid	45.1		
Phosphate Fertilizer	37.9		
Sulfur Plants	30.8		
Alfalfa Dehydration	19.6		
Flares	8.1		
Sulfite Pulping	6.4		
Sludge Conversion	1.2		
Unclassified		27.0	1.8
		1,464.7	100.0

*Based on 1977 survey.

Impact and cost of controls

For the 31 boilers within the 39 plants emitting greater than 20,000 ton/yr of SO_2 (18,100 m ton/yr) that use low-sulfur coal (average sulfur content of 1.3%), no SO_2 controls were applied. Thus, their emissions remained at 83,000 ton/yr (75,300 m ton/yr). (The results do not include an analysis of the availability of physically cleaned coal and desulfurized fuel oil, nor the age and useful lives of the sources.)

The application of physically cleaned coal as an SO_2 control process would affect 445 coal-fired industrial boilers with capacities less than 75 MW_t. These uncontrolled boilers presently emit about 730,000 ton/yr of SO_2 (662,000 m ton/yr). The use of physically cleaned coal would reduce these uncontrolled emissions by about 30%, to a level of 511,000 ton/yr (464 m ton/yr). Approximately 12.2 × 10^6 ton/yr of clean coal (11 × 10^6 m ton/yr) or 16 × 10^6 ton/yr (14.5 × 10^6 m ton/yr) of raw coal would be required to achieve this reduction. Industry would incur a total annual premium of $46 million solely for coal preparation.

Uncontrolled coal-fired industrial boilers with capacities greater than 75 MW_t emit 1,044,000 ton/yr of SO_2 (947,000 m ton/yr). Applying FGD processes to these boilers would reduce the SO_2 emissions to 104,000 ton/yr (94,700 m ton/yr), a 90% reduction. Retrofitting FGD systems to achieve this reduction would require an industry-wide capital investment of $2.0 billion. The annual cost of utilizing FGD technology to reduce SO_2 emissions would be $565 million per year.

Currently, oil-fired industrial boilers generate about 669,000 ton/yr (607,000 m ton/yr) of uncontrolled SO_2 emissions. The use of low-sulfur fuel oil would reduce the SO_2 emissions to a level of 326,000 ton/yr (296,000 m ton/yr). To achieve this reduction, about 128 × 10^6 bbl (19.92 × 10^6 m^3) of low-sulfur oil per year would be required. Consequently, the total annual fuel premium incurred by operators of oil-fired boilers would be $314 million.

Retrofitting FGD systems and sulfuric acid process units to the non-boiler sources in the metals industry would reduce the SO_2 emissions to a level of 62,000 ton/yr (56,000 m ton/yr). To achieve this reduction, the metals industry would have to invest $420 million for retrofitting FGD systems to the emission sources. Operation of FGD systems would result in an annual cost of $128 million. The use of FGD systems in the process industry would reduce the uncontrolled SO_2 emissions from this industry to a level of 64,000 ton/yr (58,000 m ton/yr). The capital investment required to achieve this reduction would be about $580 million. The annual cost for these control systems would be $178 million.

In conclusion

Based on this preliminary study, the application of the proposed control techniques would reduce industrial emissions in plants emitting 5,000 ton/yr SO_2 (4,454 m ton/yr) or more by 63% or 2,260,000 ton/yr of SO_2 (2,050,000 m ton/yr). It would cost $3.0 billion in capital charges and

Table 3. Distribution of U.S. industrial water-tube boilers (>30 MW, capacity).

Size Range MW, (10^6Btu/h)	Average Size MW, (10^6Btu/h)	Coal	Oil	Gas	Total
30–75 (100–250)	45 (150)	1,181	1,209	1,443	3,833
75–150 (250–500)	96 (325)	326	286	302	914
150–440 (500–1,500)	220 (750)	81	60	96	237
>440 (>1,500)	700 (2,400) Coal & Oil	16	9		61
	1,265 (4,300) Gas			36	
Total		1,604	1,564	1,877	5,045

SI Conversion: W = Btu/h × 0.293

Table 4. Potential boilers after accounting for the boilers found in the 39 largest SO_2 emitters.

Average Size (MW_t)	Coal	Oil	Gas
45	1,151	1,183	1,428
96	292	258	286
220	59	47	94
700 (Coal, Oil)	16	4	—
1,265 (Gas)	—	—	36
Total	1,518	1,492	1,844

incur annual operating costs of $1.23 billion. The overall cost per ton of SO_2 removed is $544 ($600 per metric ton). The details are given in Tables 7 and 8 and an overall comparison in Table 9.

If only the top 39 plants were considered, their emissions would be reduced by 73%, or 1,186,000 ton/yr of SO_2 (1,074,000 m ton/yr). The capital costs would be $1.5 billion and the annual operating costs $0.56 billion. This results in a cost of $472 per ton of SO_2 removed for the top 39 plants ($521 per metric ton). Incrementally, for the remaining 218 sources to control SO_2 emissions instead of just the top 39 plants it will cost $0.67 billion more annually, or $620 for each additional ton ($686 per metric ton) of SO_2 removed. The application of these controls to the top 257 sources will result in a reduction of SO_2 emissions in the states east of the Rocky Mountains by 12%. If applied only to the top 39 plants, the reduction will be 7%. #

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Table 5. Distribution of SO_2 emissions by fuel and boiler size.

		Coal				Oil				Gas			All Fuels
Size (MW_t)	× Potential Boiler*	Total Capacity Giga-watts	Percent of Total Capacity	10^3 m ton SO_2/yr	Potential Boiler*	Total Capacity Giga-watts	Percent of Total Capacity	10^3 m ton SO_2/yr	Potential Boilers*	Total Capacity Giga-watts	Percent of Total Capacity	10^3 m ton SO_2/yr	Total 10^3 m ton SO_2/yr
45	1,151	51.8	49.8	622	1,183	53.2	58.4	263	1,428	64.3	40.7	46	931
96	292	28.0	26.9	337	258	24.8	27.2	123	286	27.5	17.4	20	480
220	59	13.0	12.5	156	47	10.3	11.3	51	94	20.7	13.1	15	222
700 (Coal, Oil)													
1,265 (Gas)	16	11.2	10.8	135	4	2.8	3.1	14	36	45.5	28.8	33	182
		104.0	100.0	1,250		91.1	100.0	451		158.0	100.0	114	1,815

*Nation-wide less boilers in largest 39 SO_2 emitters.

Table 6. Size distribution of boilers needed to account for two million ton of SO_2 emitted per year from plants emitting between 5,000 and 20,000 ton/yr of SO_2.

	Coal			Oil			Gas			Total	
Average Boiler Size (MW_t)	10^3 m ton SO_2/yr	10^3 m ton SO_2/yr/ Boiler	Approximate Number of Boilers*	10^3 m ton SO_2/yr	10^3 m ton SO_2/yr/ Boiler	Approximate Number of Boilers*	10^3 m ton SO_2/yr	10^3 m ton SO_2/yr/ Boiler	Approximate Number of Boilers*	Approximate Number of Boilers*	10^3 m ton SO_2/yr
45	622	1.45	429	263	9.96	264	46	0.54	85	778	931
96	337	3.09	109	123	2.08	59	20	1.18	17	185	480
220	156	7.09	22	51	4.9	10	15	2.63	6	38	222
700 (Coal, Oil)	135	22.5	6	14	15.5	1	—	—	—	7	149
1,265 (Gas)	—	—	—	—	—	—	33	15.34	2	2	33
	1,250		566	451		334	114		110	1,010	1,815

*The number of boilers in each size category that would yield the annual SO_2 emissions derived in Table 5 given the fuel quality and average boiler size and capacity factor discussed in the text.

Table 7. Impact and cost of controls for plants emitting more than 5,000 ton/yr of SO_2.

	SO_2 Emission Sources[f]				SO_2 Control Processes					
Source Category	Fuel Type	Boiler Size MW_t	Avg. Sulfur Level (%)	Uncontrolled SO_2 Emissions (1,000 m ton/yr)	Control Applied	SO_2 Reduction Achieved (%)	Controlled SO_2 Emissions (1,000 m ton/yr)	Capital Investment[d] ($10^6)	Annual Cost ($10^6)[e,g]	Cost Effectiveness[g] ($/mt SO_2 Removed)
Boilers	Coal	—[c]	1.3	75	None	—	75	—	—	—
	Coal	<75	3.0	662	Physical Coal Cleaning	30	464	—	46[a]	230
	Coal	>75	2.41	947	FGD (Lime-stone)	90	95	2,020	565	662
	Fuel Oil	All	1.64	607	Low Sulfur Fuel Oil	51[b]	298	—	314[a]	1,010
	Gas	All	0.8	153	None	—	153	—	—	—
Non-Boiler Sources (Metals Indus-try)	—		—	490	FGD (Lime-stone)[d]	89	56	420	128	293
Non-Boiler Sources (Process Indus-try)	—		—	318	FGD (Lime-stone)	82	58	580	178	685
Total				3,252		62	1,197	3,020	1,231	600

[a]The cost directly represents the premium paid by boiler operator for upgraded fuel.
[b]This reduction efficiency is set by assuming the use of 0.8% sulfur fuel oil down from an average level of 1.64%. The costs are based on resid hydrodesulfurization.
[c]Boilers in the top 39 SO_2 emitters that actually burn <2.0% sulfur coal.
[d]Includes two sulfuric acid plants.
[e]In this report annual costs include annual O&M, overhead, utilities, and annual capital-related charges equivalent to 0.13 times the total capital investment.
[f]Uncontrolled emissions for 1977.
[g]1980 $.

Table 8. Impact and cost of controls for plants emitting more than 20,000 ton/yr of SO_2.

	SO_2 Emission Sources[f]				SO_2 Control Processes					
Source Category	Fuel Type	Boiler Size MW,	Avg. Sulfur Level (%)	Uncontrolled SO_2 Emissions (1,000 m ton/yr)	Control Applied	SO_2 Reduction Achieved (%)	Controlled SO_2 Emissions (1,000 m ton/yr)	Capital Investment[g] ($10^6)	Annual Cost ($10^6)[h,g]	Cost Effectiveness[g] ($/mt SO_2 Removed)
Boilers	Coal	—[a]	1.3	75	None	—	75	—	—	—
	Coal	<75	3.0	40	Physical Coal Cleaning	30	28	—	3[a]	231
	Coal	>75	2.41	320	FGD (Limestone)	90	32	471	170	590
	Fuel Oil	All	1.64	157	Low Sulfur Fuel Oil	51[b]	76	—	81[a]	1,000
	Gas	All	0.8	39	None	—	39	—	—	—
Non-Boiler Sources (Metals Industry)	—		—	489	FGD (Limestone)[d]	89	56	420	128	296
Non-Boiler Sources (Process Industry)	—		—	318	FGD (Limestone)	82	58	580	178	685
Unclassified				27			27			
Total				1,465		73	391	1,471	557	520

[a]The cost directly represents the premium paid by boiler operator for upgraded fuel.
[b]This reduction efficiency is set by assuming the use of 0.8% sulfur fuel oil down from an average level of 1.64%. The costs are based on resid hydrodesulfurization.
[c]Boilers in the top 39 SO_2 emitters that actually burn <2.0% sulfur coal.
[d]Includes two sulfuric acid plants.
[e]In this report annual costs include annual O&M, overhead, utilities, and annual capital-related charges equivalent to 0.13 times the total capital investment.
[f]Uncontrolled emissions for 1977.
[g]1980 $.

Table 9. Summary of results.

	Plants Emitting More Than	
	18,000 m ton/yr	4,454 m ton/yr
Uncontrolled SO_2 Emissions (10^3 m ton/yr)	1,465	3,252
Controlled SO_2 Emissions (10^3 m ton/yr)	391	1,197
Net Reduction (10^3 m ton/yr)	1,074	2,055
% Reduction	73	63
Capital Investment ($10^6)	1,471	3,020
Annual Operating Cost ($10^6)	557	1,231
Cost Effectiveness ($/m ton of Sulfur Removed)	520	600

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